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<u>**Via Overnight Mail**</u>

February 2, 2004

Arizona Corporation Commission
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Arizona Corporation Commission
Attn: Docket Filing Window
1200 Washington Street
Phoenix, AZ 85007

Re: Docket No. E-01345A-03-0437

Dear Sir or Madam:

Please find enclosed the original and thirteen (13) copies of the Direct Testimony and Exhibits of Stephen J. Baron filed on behalf of The Kroger Co. in the above-referenced matter.

Please place this document of file.

Very Truly Yours,

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY

MLKkew
Attachments

2

CERTIFICATE OF SERVICE

I hereby certify that true copy of the foregoing was served by regular U.S. mail (unless otherwise noted), this 2nd day of February, 2004.

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BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	)	
Arizona Public Service Company for	)	
A Hearing to Determine the Fair Value of the	)	**Docket No. E-01345-03-0437**
Utility Property of the Company for Ratemaking	)	
Purposes, to Fix a Just and Reasonable Rate of Return,	)	
And for Approval of Purchased Power Contract	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

Arizona Corporation Commission
DOCKETED

FEB 03 2004

DOCKETED BY CAR

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2004

BEFORE THE

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In the Matter of the Application of	)	
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A Hearing to Determine the Fair Value of the	)	**Docket No. E-01345-03-0437**
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Purposes, to Fix a Just and Reasonable Rate of Return,	)	
And for Approval of Purchased Power Contract	)	

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BEFORE THE

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Purposes, to Fix a Just and Reasonable Rate of Return	**)**
And for Approval of Purchased Power Contract	**)**

DIRECT TESTIMONY OF STEPHEN J. BARON

Qualifications and Summary

Q. Please state your name and business address.

A. My name is Stephen J. Baron. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by who are you employed?

A. I am the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies and industrial electricity consumers. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and industrial consumer groups throughout the United States.

Q. Please state your educational background.

A. I graduated from the University of Florida in 1972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

Q. Please describe your professional experience.

A. I have more than twenty-five years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Baron Exhibit ____ (SJB-1)

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Kroger Co. Kroger has approximately 36 stores in the APS service territory operating under the names Fry's, Fred Meyer and Smith's. These stores consume in excess of 100 million kWhs per year on the APS system.

Q. What is the purpose of your testimony?

A. I will be presenting testimony on a number of cost of service and rate design issues that affect Kroger's service on APS Rate Schedule E-32. This includes the proposed allocation of the $175 million revenue requirement increase among rate classes without consideration of the cost of service results presented by the Company in this proceeding.[1]

With regard to rate design, I will discuss the proposal by APS to recognize cost differences among customers served at different service voltages in its E-32 rate design. Kroger does not oppose the incorporation of voltage differentials in the E-32 rate design, but our analysis of the Company's methodology indicates that there is a problem with the calculation of the specific voltage differential factors being proposed. The Company's proposal would require customers served directly off of the secondary transformer to subsidize those customers served off of the secondary lines. This is contrary to the Company's own cost of service study. I propose to correct this misallocation by providing all customers over 100 kW a secondary function discount of $0.94/kW/month. I will also discuss my recommendation that customers served at secondary be permitted a six-month "window" in which to purchase the secondary transformer and facilities serving its load, if the Commission approves the Company's proposed rate E-32 voltage credits. Following such a purchase, the customer would then become a primary customer for tariff purposes.

I will address the issue of the Company's proposed assignment of the entirety of the rate E-32 "subsidy" payment to the distribution charges of the rate. Based on the

1 Kroger is not presenting testimony on the Company's requested revenue increase in this case. For purposes of my testimony, I have utilized the APS requested incease of $175 million. This should not be construed as

Company's cost of service study, rate E-32 is paying substantial subsidies to other APS rate classes. In its unbundling analysis, the Company is proposing to collect the entirety of this subsidy in the distribution charge. The impact of this is to exacerbate the difference of the Company's proposed distribution rate and a cost-based rate. In effect, with the entire subsidy now being recovered in the distribution charges (as opposed to the overall rate), the subsidy impact is amplified.

Revenue Allocation and Cost of Service

Q. Have you reviewed the Company's 2002 test year cost of service study filed in this proceeding?

A. Yes. The Company is utilizing a 4 coincident peak cost of service study in this proceeding. As discussed by APS witness Alan Propper, in response to a discovery request (LCA 2.14), APS has traditionally used a 4 CP allocation method because of the pronounced demands on the system during the summer months. This appears to be a reasonable methodology for allocating APS production related costs and is also consistent with the methodology used to develop the OATT transmission rates for APS (according to the Company's response to Data Request LCA 2.60). As such, it is reasonable to rely on the Company's filed 4 CP cost of service study for the

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an endorsement of the Company's requested increase.

purposes of assessing the reasonableness of its proposed rates and charges in this case.

Q. **What are the relative class rate of return results produced by the Company's test year 2002 4 CP cost of service study?**

A. The table below summarizes the rates of return and the relative rate of return indices ("ROR Index") for each of the major rate classes using the results of the Company's 4 CP study.

TABLE 1
Comparison of Relative Rates of Return
4 Coincident Peak Cost of Service Study

Class	Rate of Return	Rate of Return Index
Residential	4.34%	69%
General Svc	9.00%	144%
Irrigation	0.64%	10%
Street Light	2.48%	40%
Dusk to Dawn	3.08%	49%
Total Retail	6.27%	100%

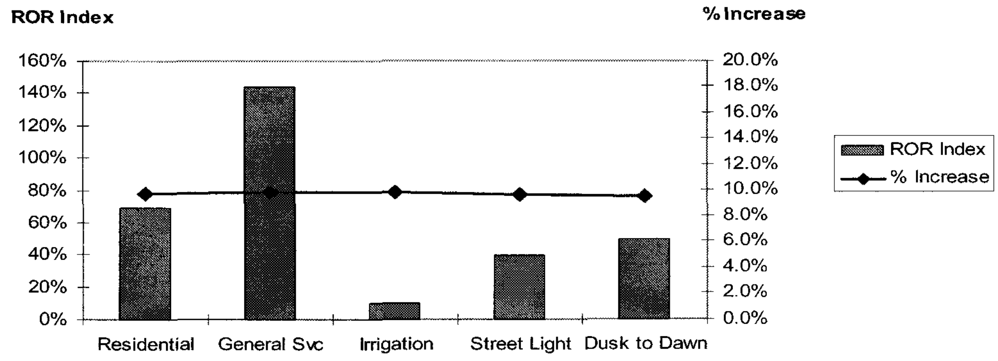
Based on these results, the residential class is paying less than 70% of its allocated cost of service under present rates, while general service customers are paying a relative rate of return that is approximately 144% of the system average. This is a substantial difference and one that should be addressed in this rate proceeding.

Q. **Has APS made any proposals in this case that would address the substantial disparities between present rates and cost of service among its retail rate classes?**

A. No. APS has not made any attempt to mitigate the cost disparities in this case. The chart below (Figure 1) compares the relative rate of return indices for each of the major rate classes to the proposed percentage rate increases recommended by APS in this proceeding. Despite the substantial variation in relative rate of return and the concomitant subsidies being paid by general service customers, APS is recommending an equal across-the-board percentage increase for each rate class.[2] In fact, when the proposed CRCC is included, residential customers are actually receiving an increase (on a percentage basis) lower than the retail average, while general service customers receive an increase greater than average.

[2] Within each revenue class (e.g., residential), the Company has proposed different increases to different rate schedules and/or rate components. However, this does not adequately respond to the substantial subsidies in the Company's rates.

FIGURE 1
Proposed % Increase vs. ROR Index



Q. Do the subsidies that you have identified in the Company's present rates occur if costs are measured using alternative cost of service methodologies?

A. Yes. In response to Data Request LCA 2.33, the Company provided the results of cost of service studies using a 12 CP production demand allocation method and a "peak and average" method. Table 2 summarizes the results of these two studies for the major rate classes. As can be seen, the subsidies paid by general service customers are substantial under either study.

TABLE 2
Comparison of Relative Rates of Return
12 CP and "Peak & Average" Cost of Service Studies

	12 CP		Peak & Average	
Class	Rate of Return	ROR Index	Rate of Return	ROR Index
Residential	4.86%	78%	4.93%	78%
General Svc	8.22%	131%	8.30%	131%
Irrigation	-1.43%	-23%	2.00%	32%
Street Light	1.80%	29%	1.04%	16%
Dusk to Dawn	2.55%	41%	1.70%	27%
Total Retail	6.27%	100%	6.34%	100%

Q. Are you recommending that proposed rates in this case be set at cost of service, thus eliminating all subsidies?

A. No. Based on the Company's test year cost of service study, general service rates would have to be decreased at the Company's requested revenue requirement increase, if all subsidies were removed. Though this would be an ideal result and one that should be recognized as a longer-term goal in future rate proceedings, I am not recommending the elimination of all subsidies in this proceeding. However, there is no justification for ignoring the cost of service results and simply increasing rates equally across-the-board as the Company has done. Some mitigation of the subsidies should be made in this case.

Q. **Have you developed an alternative allocation of the Company's proposed revenue increase that would reduce the subsidies that you have discussed?**

A. Yes. Baron Exhibit ____(SJB-2) presents a revenue allocation analysis using the Company's cost of service study as the basis for allocating the requested increase. The Company is proposing to recover $166.8 million in increased revenues from rate schedules. The remaining revenues required to produce the overall $175 million increase will be recovered through the CRCC.

As shown in the first "box" in Exhibit ____(SJB-2), under present rates, residential customers are benefiting from a subsidy of $75.6 million, while general service customers are paying a subsidy of $79.9 million. If the cost of service study was used directly to allocate the requested $166.8 million increase, residential customers would be assigned a $169.4 million increase, while general service customers would receive a $9.7 million decrease. This is the result that would be obtained if 100% of the current subsidies were eliminated in this proceeding.

Q. Are you recommending that all of the subsidies be removed from rates in this proceeding?

A. No. Obviously, it would be unreasonable to increase residential rates by such a substantial amount in a single rate proceeding. However, it is also unreasonable to completely ignore the results of the Company's cost of service study (and other cost of service analyses prepared by the Company in response to data requests).

Q. In light of the impact of completely eliminating the subsidies in this proceeding, do you have an alternative recommendation that would recognize the results of the Company's cost of service study in allocating the increase?

A. Yes. I believe that it is appropriate to make some progress towards eliminating the subsidies contained in present rates in this case. A reasonable and balanced approach would be to reduce class subsidies by 25% as a means of moving towards the objective of setting rates based on cost of service. The analysis presented in Exhibit ____(SJB-2) shows the results of a 25% subsidy reduction in the allocation of the requested $166.8 million increase. As can be seen in the third "box" in Exhibit ____(SJB-2), eliminating 25% of the subsidy would result in an increase to residential customers of $112.75 million (12.67%), while producing a $50.2 million increase or 5.68% to the general service class. A 25% subsidy reduction criterion for allocating the approved revenue requirement increase in this case would still result in proposed rates that contain substantial subsidies, though these subsidies will be reduced going forward. Subsequent rate cases should be used to further reduce subsidies in future periods.

Q. **Beyond the general objective of reducing subsidies among customer classes, are there any additional reasons why the Commission should use this rate case as an opportunity to make some progress towards subsidy reduction?**

A. Yes. The Company has filed its rate schedules on both a bundled and unbundled basis in this proceeding. For customers that pursue direct access, such customers would continue to pay the distribution and transmission charges in the rate schedule, but not pay the generation charge. The generation charge effectively becomes the shopping credit or price to compare for each rate schedule. To avoid the potential for creating additional stranded costs, the Company has designed its rates so that the generation component reflects cost, while the distribution component reflects costs plus any subsidy (or deficit) allocated to the class. Table 3 shows the results of an analysis of the implicit distribution rate of return under proposed rates for each rate class.

As can be seen from Table 3, the rate of return on distribution for residential customers is about half the overall retail rate of return, while for general service customers it is about twice the overall system rate of return. It is unreasonable for the Company's distribution rates for general service customers to produce a 200% rate of return index. If APS was a "wires" company, distribution would effectively be its only retail regulated service. It is appropriate in this proceeding, to make some progress towards aligning distribution rates with costs.

TABLE 3
Rates of Return on Distribution Investment
(@ Proposed Rates)

Class	Distribution Rate of Return	Rate of Return Index
Residential	4.21%	49%
General Svc	17.30%	200%
Irrigation	-20.89%	-241%
Street Light	3.74%	43%
Dusk to Dawn	4.49%	52%
Total Retail	8.67%	100%

Rate E-32 Rate Design

Q. Have you reviewed APS' proposed Rate E-32 rate design?

A. Yes. The Company has proposed to unbundle of all of its rate schedules, including rate E-32. Among the changes the Company is making to rate E-32 is an introduction of a demand charge differential based on service voltage.[3] APS has disaggregated its distribution demand charges into secondary, primary and transmission service charges for Rate E-32.[4] The current rate E-32 does not recognize cost differences that exist between customers who utilize different distribution facilities due to the voltage at which they take service. The APS proposal is an attempt to de-average the E-32 rate so that customers served at higher voltages (transmission, for example) will not be charged for lower voltage facilities (primary and secondary transformers and lines) that are not required to serve these customers. Likewise, customers who take service directly from the primary distribution system will not be charged for secondary transformer costs and secondary line costs. This is all sound ratemaking. But the Company's proposal falls short when it comes to secondary voltage customers. There are two types of secondary voltage customers: 1) those served directly off of the secondary transformer, who impose less cost on the system; and 2) those served off of the secondary lines who impose more costs on the system. However, the Company's proposal establishes a <u>single</u> distribution demand charge for both types of secondary voltage E-32 customers.

3 This is applicable to customers with demand greater than 20 kW. Rate E-32 also provides for voltage differentials in its non-demand metered rate for customers whose demands are 20 kW or below.

4 For Rate E-32 customers below 20 kW, customers are served at either secondary or primary voltage only.

Q. You indicated that some secondary voltage customers are served directly from a secondary transformer, while some secondary customers are served from secondary lines. Does the APS proposal recognize this distinction?

A. No. Under the APS proposal, all secondary voltage customers are treated alike. There is no recognition of the differences in the facilities that are required to serve these two types of secondary customers. The Company's cost studies show that all secondary customers whose demands are greater than 100 kW are served directly from transformers and do not impose any secondary line costs to APS. For customers below 100 kw, some may be served from the transformer and some may be served off of a secondary line. The Company's proposal fails to recognize this distinction. The Company's proposal requires secondary customers over 100 kW in size to subsidize those secondary customers below 100 KW.

Q. Would you please elaborate your concerns with the Company's unbundled E-32 rate?

A. Though I have no objection to the concept of incorporating a voltage differential within the demand charges of the E-32 rate, the development of the voltage discounts or credits proposed by APS for secondary voltage customers is not reasonable and does not follow the results of its own functional cost analysis, the very analysis that it relied on to develop the E-32 voltage differentiated rates. APS has improperly proposed to charge secondary voltage customers with demands over 100 kW a secondary function demand charge of $0.94/KW, even though these customers do not impose secondary line costs on the system.

Q. What level of primary and transmission discounts is the Company's proposing for rate E-32?

A. Rate E-32 is really two different rate schedules, one for customers whose demands are 20 kW and below, and the other for customers with demand meters who have monthly demands in excess of 20 kW per month.[5] For the demand-metered portion of Rate E-32, applicable to customers with monthly demands greater than 20 kW, the primary discount is a $1.59 per kW and the transmission discount is $4.60 per kW.

These discounts are applied to the secondary service kW charge to produce the respective primary and transmission voltage distribution charges. Thus, for example, the secondary demand charge for the first 500 kW per month is $6.348 per kW, while the primary charge for the same service is $4.758 per kW (a difference of $1.59).

[5] The rate for customers whose demands are 20 kW or less is an energy-only, non-demand rate.

Q. How did the Company develop these primary and transmission voltage discounts (relative to the secondary distribution charge) from the functional cost of service study results?

A. APS utilized the results of its general service class functional revenue requirement study to develop the voltage differentials. Baron Exhibit ____(SJB-2), pages 1 through 4 provide the information relied on by APS to develop the E-32 voltage discounts. Page 1 of the exhibit is the workpaper supporting the voltage credits.

The first portion of page 1 contains the revenue requirements for small, medium and large general service customers by distribution function. There are four functions associated with distribution service in the Company analysis. These are: distribution substations, distribution primary lines, distribution transformers and a distribution secondary function. For example, for small GS customers, the distribution revenue requirements are $7.2 million, $33.4 million, 9.6 million and $8.0 million respectively for the four functions. These results are obtained from the functional cost of service study summarized in pages 2 through 4 of Exhibit ____(SJB-2). Functional revenue requirements for SGS on page 2, while data for medium general service and large general service are contained on pages 3 and 4 of SJB-2. With regard to the revenue requirement for the secondary transformation and secondary services, functions ($9,597,390 and $7,997,825 for small general service), these are shown as a combined revenue requirement on page 2 of the exhibit (total of $17,595,216). Similar analyses are performed for medium and large general service customers.

Q. Do medium and large general service customers have any "secondary function" revenue requirements, based on the Company's analysis?

A. No. As can be seen on line 1, page 1 of Exhibit ____(SJB-2), only small general service customers whose demands are between 0 and 100 kW have secondary function revenue requirements ($7,997,825). Medium and large general service customers do not have any revenue requirements associated with this function, even though some are classified as secondary customers (see line 2 and 3).

Q. Would you continue explaining page 1 of Exhibit ____(SJB-2)?

A. The second portion of page 1 of Exhibit ____(SJB-2) shows the annual kW demand determinants for each of the corresponding revenue requirements shown in the first part of the exhibit. These demands are used to unitize the functional costs in the third portion of the exhibit for each of the four functions (substations, primary, transformers, and secondary), by general service rate class. As can be seen on line 9 (page 1) of the exhibit, there is a $0.94 per kW cost associated with the small general service "secondary" revenue requirement. However, none of this cost is attributable to service by customers above 100 kW (medium and large general service customers). This can be seen on lines 10 and 11 of the exhibit under the column labeled "secondary function."

Q. How did the Company calculate the overall primary and transmission level voltage discounts in its rate design?

A. This is shown on lines 13 and 14 of page 1 of Exhibit____(SJB-2). The Company calculated a weighted average of unit costs associated with the secondary transformation function ("xformer function") of $0.65 per kW plus a "secondary" function cost of $0.94 per kW. This produced a <u>total primary service</u> discount of $1.59 per kW. For transmission service customers, an additional discount associated with avoiding primary function costs of $2.48 per kW is added in for a total <u>transmission discount</u> of $4.60 per kW (shown in line 14).

Q. What problem have you identified with the Company's analysis?

A. The problem with the Company's methodology is that the primary discount of $1.59 includes both the transformation credit of $0.65 and a secondary function credit of

\$0.94 for any customer taking service at the primary voltage. Correspondingly, any customer taking service at the secondary voltage is implicitly assumed to incur costs of \$0.65 and \$0.94 associated with this service. However, as can be seen from lines 10 and 11 of page 1 of Exhibit ___(SJB-2), customers who take service under the medium and large general service category (demands above 100 kW) do not impose any costs associated with the \$0.94 per kW "secondary" function. These "over 100" kW secondary customers who are taking service under the medium and large general service categories should be given a credit of \$0.94 per kW, relative to the basic secondary rate.

Q. Does Kroger take service under the medium general service category?

A. Yes. Kroger facilities take service under the rate E-32 and generally have demands in the range of 500 kW per month. Under the Company's proposed rate design, these customers are implicitly charged a secondary function demand charge of \$0.94 per kW, even though they do not impose any costs for this function, based on the Company's cost of service analysis. The Company relied on its functional cost of service study to develop the primary and transmission voltage discounts, which is reasonable. However, the Company then imposed an implicit "secondary function" demand charge on medium and large general service secondary customers even though these customers do not impose these costs on the system.

Q. How could this problem be addressed in the Company's rate design?

A. All medium and large general service customers (those whose demands are greater than 100 kW) should receive a "secondary function" discount of $0.94 per kW per month, relative to secondary customers whose demands are below 100 kW. A proper E-32 rate design would reflect transmission, primary and secondary function discounts for those customers above 100 kW.

Q. Do all smaller general service customers whose demands are less than 100 kW impose secondary function revenue requirements on the Company?

A. No. Unfortunately, customers in the small GS category (0 to 100 kW) may or may not impose the secondary function costs on the system, depending on whether such a customer takes service directly from a distribution transformer. Thus, some demand metered customers whose demands are between 20 kW and 100 kW take service directly from the transformer and some take service off of a secondary line, which means they impose additional costs on the system. <u>What is clear however, is that medium general service and large general service secondary customers (greater than 100 kw) do not impose any such costs on the system.</u>

Q. Why did the Company propose to charge secondary voltage customers with demands over 100 kW for this secondary function cost of $0.94/KW if it knew that those customers did not impose that cost?

A. I think that the Company believed that it faced a dilemma. The Company might have just imposed these costs on all small GS customers (0 to 100 KW). Then, some of these "under 100" kW customers would properly be allocated this cost and some would not. To solve this perceived dilemma it appears that APS elected to allocate this cost to all GS secondary customer, small, medium and large. The problem with this "solution" is that none of the medium and large general service secondary customers should be assigned this cost. This is the wrong solution. It would be much more equitable to assign such costs to the small GS customers since this is proper as to most of them, rather than to make the assignment to the medium and large GS customers since this is not proper for any of them. It is better to be mostly right than totally wrong.

Q. How would you propose redesigning Rate E-32 to recognize the rate design problem you have identified with the primary and transmission voltage discounts?

A. Ideally, the Company's customer information system could identify whether small general service customers between 20 kW and 100 kW are taking service directly from a distribution transformer or, alternatively, from a secondary line. This information could be used to determine whether such a customer should receive the $0.94 per kW secondary function discount. For all customers above 100 kW (medium and large GS customers), the $0.94 per kW discount should always apply.

Unfortunately, it is my understanding that the Company's customer information system does not record the type of information currently that would permit such a rate design. Assuming that this cannot easily be modified, my recommendation would be to provide the $0.94 per kW secondary function discount to all Rate E-32 customers whose demands are greater than 100 kW per month. As in all rate designs, this proposal is a compromise that reflects the availability of detailed billing information. My recommendation would be to redesign Rate E-32 to reflect a "secondary function" credit of $0.94 per kW for all secondary customers whose demands exceed 100 kW.

Q. Have you prepared an analysis that corrects the Company's Rate E-32 voltage differential analysis?

A. Yes. Baron Exhibit _____(SJB-4) shows a corrected calculation of the Rate E-32 voltage differentials. As can be seen, I have added an additional discount to reflect an appropriate credit for customers served at the secondary transformer level. This would be applicable to all customers over 100 kW, for the reasons that I previously discussed.

Q. Do you have any additional comments on the Company's proposal to initiate voltage differentiation for rate E-32?

A. Yes. This case is the first time that the Company is proposing to recognize voltage differentials in its rate E-32 design. As I indicated, Kroger does not oppose the concept of voltage differentials as a part of general service rate design. Because no voltage differentiation was previously recognized in rate E-32, there was no economic incentive for a customer to purchase the secondary transformer and related facilities (if any) at the customer's site. However, with the change in the tariff, it may now be economic for customers to make such a purchase and become a primary customer.

Q. Do you have any recommendations to facilitate the purchase of secondary transformers?

A. Yes. I believe that it would be reasonable for the Commission to adopt a tariff provision that would permit customers on rate E-32 to elect to purchase the secondary facilities serving the customer within a six-month period ("window") from the effective date of an order approving the rate E-32 voltage credits. Customers should be permitted to purchase these facilities at depreciated cost, during this six-month period.

Moving to a voltage differentiated distribution demand charge makes sense. But for many secondary voltage customers this will be a "theoretical change" only unless they are permitted to buy the facilities that make the move to primary possible. It is not likely to make economic sense for a customer to remove a perfectly good utility owned transformer and replace it with a brand new one. Nor would this be a good public policy to promote. Since this is the first time that APS has offered voltage differentiated rates, it would make more sense to give customers a one-time six month opportunity to buy the secondary facilities serving the customer. If the purchase is at depreciated net book cost, then there is neither profit nor loss for the utility.

Q. Does that complete your testimony?

A. Yes.

BEFORE THE

ARIZONA CORPORATION COMMISSION

In the Matter of the Application of	**)**
Arizona Public Service Company for	**)**
A Hearing to Determine the Fair Value of the	**) Docket No. E-01345-03-0437**
Utility Property of the Company for Ratemaking	**)**
Purposes, to Fix a Just and Reasonable Rate of Return,	**)**
And for Approval of Purchased Power Contract	**)**

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

KROGER CO.

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

February 2004

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

Expert Testimony Appearances
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As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore-casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

Expert Testimony Appearances
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As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and and proposed merger with
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

Expert Testimony Appearances
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Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035- E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

Expert Testimony Appearances
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Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

Expert Testimony Appearances
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As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Comission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross- Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

Expert Testimony Appearances
of
Stephen J. Baron
As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Expert Testimony Appearances
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As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI 98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER-2854-000 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

Expert Testimony Appearances
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As of January 2004

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and The Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000, ER03-583-001, and ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, and ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.

ARIZONA PUBLIC SERVICE COMPANY
Computation of Rate Increase Necessary to Reduce Class Subsidy by 25%

	Total ACC Jurisdiction	Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn Lt
COST OF SERVICE AT PRESENT RATES						
REVENUES FROM RATES	1,839,197,107	911,780,435	908,197,108	2,257,000	11,567,156	5,395,408
PROFORMA TO REVENUES FROM RATES	(47,613,375)	(21,882,852)	(24,601,762)	(157,808)	(773,504)	(197,449)
Revenue (Existing Rates)	1,791,583,732	889,897,583	883,595,346	2,099,192	10,793,652	5,197,959
TOTAL OPERATING EXPENSES	1,676,275,581	858,349,133	798,491,130	2,284,920	12,243,225	4,907,174
OTHER ELECTRIC REVENUE	148,562,410	71,186,642	74,249,338	214,786	2,582,662	328,981
Net Operating Expenses	1,527,713,171	787,162,491	724,241,791	2,070,134	9,660,562	4,578,192
Net Operating Income	263,870,561	102,735,092	159,353,555	29,058	1,133,090	619,767
Rate Base	4,207,475,999	2,367,111,987	1,769,998,307	4,571,046	45,676,181	20,118,478
Rate of Return	6.27%	4.34%	9.00%	0.64%	2.48%	3.08%
Rate of Return Index	1.000	0.692	1.436	0.101	0.396	0.491
Subsidy at Present Rate of Return	(0)	75,566,292	(79,915,134)	425,808	2,861,947	1,061,087
Percentage Increase		8.49%	-9.04%	20.28%	26.52%	20.41%
Increase to Equalized Proposed Rate of Return	166,830,944	169,424,826	(9,732,799)	607,055	4,673,056	1,858,806
Percentage Increase		19.04%	-1.10%	28.92%	43.29%	35.76%
APS Proposed Percentage Increases	9.31%	9.31%	9.31%	9.34%	9.31%	9.31%
Proposed Class Rate Increase	166,830,944	82,848,343	82,297,717	196,065	1,004,889	483,930
Less: Incremental Income Taxes	(65,898,223)	(32,725,096)	(32,507,598)	(77,445)	(396,931)	(191,152)
Net Income @ proposed rates	364,803,282	152,858,340	209,143,673	147,677	1,741,048	912,544
Rate of Return @ proposed rates	8.67%	6.46%	11.82%	3.23%	3.81%	4.54%
Rate of Return Index	1.000	0.745	1.363	0.373	0.440	0.523
Subsidy at Company Proposed Rates	-	86,576,482	(92,030,516)	410,991	3,668,167	1,374,876
Proposed Subsidy (75% of Present)	(0)	56,674,719	(59,936,350)	319,356	2,146,460	795,815
Required Rate Increase	**166,830,944**	**112,750,107**	**50,203,551**	**287,699**	**2,526,596**	**1,062,991**
Percentage Increase	**9.31%**	**12.67%**	**5.68%**	**13.71%**	**23.41%**	**20.45%**
Net Income with Proposed Subsidy Reduction	364,803,282	170,948,907	189,726,703	203,116	2,661,681	1,262,876
Rate of Return	**8.67%**	**7.22%**	**10.72%**	**4.44%**	**5.83%**	**6.28%**
Rate of Return Index		**0.833**	**1.236**	**0.512**	**0.672**	**0.724**

ARIZONA PUBLIC SERVICE
DEVELOPMENT OF RATE E-32 VOLTAGE DIFFERENTIALS

Line		Substation Function	Primary Function	Xformer Function	Secondary Function	
I.	GS Revenue Requirement by Function for COSS (provided in AP-WP3)					
1	Small GS (0<=kW<100)	$ 7,164,185	$33,378,160	$ 9,597,390	$7,997,825	
2	Medium GS (100 <= kW < 1000 kW)	$ 8,734,536	$40,587,793	$ 9,931,667	$ -	
3	Lg GS (1000 <= kW < 3000)	$ 2,086,023	$ 9,478,326	$ 1,975,544	$ -	
4	Sum of Sm, Med, Large	$17,984,744	$83,444,279	$21,504,601	$7,997,825	
II.	GS KW by Function (Annual Determinants)					
5	Small GS (0<=kW<100)	14,175,878	14,165,657	14,144,048	8,535,206	
6	Medium GS (100 <= kW < 1000 kW)	16,074,547	16,014,930	15,860,418	-	
7	Lg GS (1000 <= kW < 3000)	3,577,430	3,486,660	2,887,153	-	
8	Sum of Sm, Med, Large	33,827,855	33,667,247	32,891,618	8,535,206	
III.	Unit Costs by Function ($/kW)					
9	Small GS (0<=kW<100)	$ 0.51	$ 2.36	$ 0.68	$ 0.94	line 1 / line 5
10	Medium GS (100 <= kW < 1000 kW)	$ 0.54	$ 2.53	$ 0.63		line 2 / line 6
11	Lg GS (1000 <= kW < 3000)	$ 0.58	$ 2.72	$ 0.68		line 3 / line 7
12	Sum of Sm, Med, Large	$ 0.53	$ 2.48	$ 0.65	$ 0.94	line 4 / line 8
13	**Primary Discount < 3MW** (line 12 - primary customer gets credited for last two functional amounts)			$ 0.65	$ 0.94	**TOTAL $ 1.59**
14	**Transmission Discount < 3 MW** (line 12 - transmission customer gets credited for all four functional amounts)	$ 0.53	$ 2.48	$ 0.65	$ 0.94	**TOTAL $ 4.60**

SMALL GENERAL SERVICE

		Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)
	Rate Base			
1)	Rate Base (excluding Cust. Advances & Deposits)	$25,562,502	$155,495,091	$80,987,849
2)	Regulatory Assets			
3)	Customer Accounts			
4)	Cust. Service & Info and Sales Expense			
5)	Customer Deposits	(762,274)	(4,636,867)	(2,415,060)
6)	Customer Advances	(461,408)	(2,806,718)	(1,461,847)
7)	Total Rate Base	$24,338,819	$148,051,505	$77,110,942
8)	Retail Earned ROR @ 8.67%			
9)	Return on Rate Base (Line 8 * Line 7)	$2,110,176	$12,836,066	$6,685,519
	Computation of Income Taxes			
10)	Weighted Cost of Long Term Debt @ 3.14%			
11)	Tax Rate @ 39.50%			
12)	Income Taxes ((Line 8-Line10)(Line 7)(Line 11))/(1-Line 11)	$879,456	$5,349,676	$2,786,318
	Expenses			
13)	Expenses	$4,384,950	$16,568,901	$8,801,403
14)	Regulatory Assets			
15)	Customer Accounts			
16)	Cust. Service & Info and Sales Expense			
17)	Total Expenses	$4,384,950	$16,568,901	$8,801,403
	Revenue Requirement			
18)	Return, Income Taxes, and Expenses (Line 9 + Line 12 + Line 17)	$7,374,582	$34,754,642	$18,273,239
19)	Less: Revenue Credits	$210,397	$1,376,482	$678,024
20)	Class Low Income, E-3 & E-4 Discounts	$0	$0	$0
21)	**REVENUE REQUIREMENT @8.67%**	**$7,164,185**	**$33,378,160**	**$17,595,216**

MEDIUM GENERAL SERVICE

		Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)
	Rate Base			
1)		$31,197,737	$189,335,921	$46,847,019
2)	Regulatory Assets			
3)	Customer Accounts			
4)	Cust. Service & Info and Sales Expense			
5)	Customer Deposits	(974,197)	(5,912,302)	(1,462,869)
6)	Customer Advances	(592,420)	(3,595,337)	(889,587)
7)	Total Rate Base	$29,631,120	$179,828,282	$44,494,562
8)	Retail Earned ROR @ 8.67%			
9)	Return on Rate Base (Line 8 * Line 7)	$2,569,018	$15,591,112	$3,857,679
	Computation of Income Taxes			
10)	Weighted Cost of Long Term Debt @ 3.14%			
11)	Tax Rate @ 39.50%			
12)	Income Taxes ((Line 8-Line10)(Line 7)(Line 11))/(1-Line 11)	$1,070,687	$6,497,894	$1,607,761
	Expenses			
13)	Expenses	$5,351,610	$20,174,837	$4,859,377
14)	Regulatory Assets			
15)	Customer Accounts			
16)	Cust. Service & Info and Sales Expense			
17)	Total Expenses	$5,351,610	$20,174,837	$4,859,377
	Revenue Requirement			
18)	Return, Income Taxes, and Expenses (Line 9 + Line 12 + Line 17)	$8,991,315	$42,263,843	$10,324,817
19)	Less: Revenue Credits	$256,779	$1,676,049	$393,149
20)	Class Low Income, E-3 & E-4 Discounts	$0	$0	$0
21)	**REVENUE REQUIREMENT @8.67%**	**$8,734,536**	**$40,587,793**	**$9,931,667**

LARGE GENERAL SERVICE

		Distribution (Substations)	Distribution (Primary Lines)	Distribution (Transformers, Secondary & Services)
	Rate Base			
1)		$7,458,215	$44,272,522	$9,359,243
2)	Regulatory Assets			
3)	Customer Accounts			
4)	Cust. Service & Info and Sales Expense			
5)	Customer Deposits	(243,363)	(1,444,621)	(305,394)
6)	Customer Advances	(148,081)	(879,017)	(185,825)
7)	Total Rate Base	$7,066,771	$41,948,883	$8,868,024
8)	Retail Earned ROR @ 8.67%			
9)	Return on Rate Base (Line 8 * Line 7)	$612,689	$3,636,968	$768,858
	Computation of Income Taxes			
10)	Weighted Cost of Long Term Debt @ 3.14%			
11)	Tax Rate @ 39.50%			
12)	Income Taxes ((Line 8-Line10)(Line 7)(Line 11))/(1-Line 11)	$255,350	$1,515,776	$320,436
	Expenses			
13)	Expenses	$1,279,370	$4,717,493	$964,830
14)	Regulatory Assets			
15)	Customer Accounts			
16)	Cust. Service & Info and Sales Expense			
17)	Total Expenses	$1,279,370	$4,717,493	$964,830
	Revenue Requirement			
18)	Return, Income Taxes, and Expenses (Line 9 + Line 12 + Line 17)	$2,147,409	$9,870,237	$2,054,124
19)	Less: Revenue Credits	$61,386	$391,912	$78,580
20)	Class Low Income, E-3 & E-4 Discounts	$0	$0	$0
21)	**REVENUE REQUIREMENT @8.67%**	**$2,086,023**	**$9,478,326**	**$1,975,544**

Exhibit SJB-4
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ARIZONA PUBLIC SERVICE
CORRECTED RATE E-32 VOLTAGE DIFFERENTIAL ANALYSIS

Line		Substation Function	Primary Function	Xformer Function	Secondary Function	
I.	GS Revenue Requirement by Function for COSS (provided in AP-WP3)					
1	Small GS (0<=kW<100)	$ 7,164,185	$33,378,160	$ 9,597,390	$7,997,825	
2	Medium GS (100 <= kW < 1000 kW)	$ 8,734,536	$40,587,793	$ 9,931,667	$ -	
3	Lg GS (1000 <= kW < 3000)	$ 2,086,023	$ 9,478,326	$ 1,975,544	$ -	
4	Sum of Sm, Med, Large	$17,984,744	$83,444,279	$21,504,601	$7,997,825	
II.	GS KW by Function (Annual Determinants)					
5	Small GS (0<=kW<100)	14,175,878	14,165,657	14,144,048	8,535,206	
6	Medium GS (100 <= kW < 1000 kW)	16,074,547	16,014,930	15,860,418	-	
7	Lg GS (1000 <= kW < 3000)	3,577,430	3,486,660	2,887,153	-	
8	Sum of Sm, Med, Large	33,827,855	33,667,247	32,891,618	8,535,206	
III.	Unit Costs by Function ($/kW)					
9	Small GS (0<=kW<100)	$ 0.51	$ 2.36	$ 0.68	$ 0.94	line 1 / line 5
10	Medium GS (100 <= kW < 1000 kW)	$ 0.54	$ 2.53	$ 0.63		line 2 / line 6
11	Lg GS (1000 <= kW < 3000)	$ 0.58	$ 2.72	$ 0.68		line 3 / line 7
12	Sum of Sm, Med, Large	$ 0.53	$ 2.48	$ 0.65	$ 0.94	line 4 / line 8
	Secondary Transformer Discount < 3MW					
13	(line 12 - primary customer gets credited for last two functional amounts)				$ 0.94	**TOTAL $ 0.94**
	Primary Discount < 3MW					
14	(line 12 - primary customer gets credited for last two functional amounts)			$ 0.65	$ 0.94	**TOTAL $ 1.59**
	Transmission Discount < 3 MW					
15	(line 12 - transmission customer gets credited for all four functional amounts)	$ 0.53	$ 2.48	$ 0.65	$ 0.94	**TOTAL $ 4.60**